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July 26, 2005

VIA OVERNIGHT MAIL

The Honorable Charles L. A. Terreni
Chief Clerk and Administrator
The Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: Docket Number 2005-3-E
Duke Power - Annual Review of Base Rates for Fuel Costs
Filing of Testimony and **Motion for Confidential Treatment**

Dear Mr. Terreni:

Pursuant to the Commission's scheduling order in the above-referenced docket, Duke Power ("Duke"), a division of Duke Energy Corporation, encloses for filing 25 copies of the direct testimony and exhibits of witnesses Janice D. Hager, M. Elliott Batson and Dwight L. Jacobs.

Certain information contained in Ms. Hager's testimony and exhibits is confidential. Therefore, pursuant to Commission Order No: 2005-226 "ORDER REQUIRING DESIGNATION OF CONFIDENTIAL MATERIALS," Duke hereby files the confidential information in a separate envelope marked "CONFIDENTIAL" and files 25 copies of a redacted non-confidential version of the such testimony and exhibits. If you have any questions or concerns, please do not hesitate to contact the undersigned.

Please consider this letter as Duke's Motion to accord confidential treatment to the testimony and exhibits so designated.

By copy of this letter, Duke serves such testimony and exhibits on all parties of record to this proceeding. The parties have previously entered into confidentiality agreements with Duke, and therefore, the confidential portions of Ms. Hager's testimony and exhibits are produced pursuant to such agreements and 26 S.C. Code Ann. Regs. 103-804(Y)(2).

Sincerely,

Lara Simmons Nichols
William F. Austin, Austin, Lewis, and Rogers, P.A.

Enclosures

cc: C. Dukes Scott, Esquire, Office of Regulatory Staff
Florence P. Belser, Esquire, Office of Regulatory Staff
Scott Elliot, Esquire

TESTIMONY OF JANICE D. HAGER

FOR

DUKE POWER

PSCSC DOCKET NO. 2005-003-E

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A. My name is Janice D. Hager. My business address is 422 South Church Street, Charlotte, North Carolina. I am Vice President, Rates and Regulatory Affairs for Duke Power, a division of Duke Energy Corporation ("Duke Power" or "the Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE POWER?

A. I am responsible for all state and federal regulatory operational filings, the design and administration of retail and wholesale rates, load research, and the handling of customer inquiries to the Office of the Regulatory Staff.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a civil engineer, having received a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. I began my career at Duke Power in 1981 and have had a variety of responsibilities across the Company in areas of piping analyses, nuclear station modifications, new generation licensing, Integrated Resource Planning and Demand Side Management. I joined the Rate Department in 1996 and my initial responsibilities included implementation of Duke Power's Open Access Transmission Tariff. I was promoted to Manager, Rate Design, and in 1999, to Manager, Rate Design and Analysis with responsibility for the Rate Design, Revenue Analysis and Load Research groups. In April 2003, I was

promoted to the position of Vice President of Rates and Regulatory Affairs for Duke Power. I am a registered Professional Engineer in North Carolina and South Carolina and am chair of the Southeastern Electric Exchange Rates and Regulation Section.

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DUKE POWER?

A. Yes. As ordered by this Commission, the books of account of Duke Power follow the uniform classification of accounts prescribed by the Federal Energy Regulatory Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the actual fuel cost data for the period April 2004 through June 2005, the historical period under review in this proceeding; the projected fuel cost information for the period July 2005 through September 2006; and the Company's recommended fuel rate for the period October 2005 through September 2006. The review period in Duke Power's 2005 fuel case covers fifteen months, April 2004 through June 2005, as a result of the transition to the new hearing schedule approved by the Commission in Docket No. 2004-324-E by Order No. 2004-603 issued on December 9, 2004. In addition, I provide an overview of Duke Power and explanations of the seven exhibits attached to my testimony.

Q. YOUR TESTIMONY INCLUDES 7 EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. Each of these exhibits was prepared at my direction and under my supervision.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS.

A. The exhibits and descriptions are as follows:

Exhibit 1 - Nuclear Plant Performance Data

Exhibit 2 - Nuclear Fuel Purchases and Inventory

Exhibit 3 - Total Company Fuel Costs Detail for the Review Period

Exhibit 4A - Coal Cost per MBTU Burned

Exhibit 4B - Nuclear Cost per MBTU Burned

Exhibit 5 - Source of Generation by Period

Exhibit 6 - Current Period Fuel Costs and Revenues

Exhibit 7 - Projected Period Fuel Costs and Revenues

Q. MS. HAGER, PLEASE PROVIDE A GENERAL DESCRIPTION OF DUKE POWER.

A. Duke Power serves more than 2 million customers in the Piedmont Carolinas with a service area that covers over 22,000 square miles. The Company operates more than 13,000 miles of transmission lines and almost 100,000 miles of distribution lines. Last year, the Company's system peak demand (single highest hour of use) was 15,407 MWs.

Duke Power's South Carolina retail customers, which represent about 25% of the Company's total customer base, consumed over 20 billion kWhs of electricity last year. Duke Power's South Carolina residential customers consumed 28% of that total, general service customers consumed 25%, and industrial customers consumed 47%.

Q. IS DUKE POWER'S LOAD GROWING?

A. Yes. Duke Power's peak demand and energy use are growing at a rate of about 1.5% per year.

Q. HOW DOES DUKE POWER MEET ITS CUSTOMERS' NEEDS FOR ELECTRICITY?

A. Duke Power meets its customers' needs for electricity through a combination of Company-owned generation, purchases of power from others, and customer demand-side options. Demand-side options include residential and non-residential programs that provide credits to customers for allowing the Company to curtail their electricity usage on occasion.

Q. MS. HAGER, PLEASE DESCRIBE DUKE POWER'S GENERATION PORTFOLIO.

A. Duke Power's generation portfolio consists of approximately 18,300 MWs of generating capacity, made up as follows:

Nuclear generation - 5,000 MWs (including Duke Power's 12.5% ownership of the Catawba Nuclear Plant)

Coal-fired generation - 7,700 MWs

Hydroelectric - 3,200 MWs

Combustion Turbines - 2,400 MWs

(Combustion turbines can operate on natural gas or fuel oil)

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF HOW THE DIFFERENT UNITS OPERATE.

A. Duke Power's generating units can be divided into three categories: base load, intermediate and peaking units. Base load units typically have very low operating costs but relatively high initial capital costs to install. Peaking units typically have higher operating costs but lower initial capital costs to install than base load units. Intermediate unit costs are in between the costs for base load and peaking units.

Duke Power's nuclear and large coal units make up its base load fleet. These units run almost continually. The Company's peaking units, combustion turbines, typically operate only on very hot or cold days to meet the short-term high demands our customers place on our systems during those times. Duke Power's intermediate coal units ramp up and down frequently to match the daily variations in load the Company sees on its system. The Company's hydroelectric units are especially good for meeting rapid changes in load as the output of these units can be changed very quickly.

The base load, intermediate, and peaking nature of units can be demonstrated by looking at the units' capacity factors. Capacity factor is a measure of total kWhs a generating unit provides annually as compared to what it could theoretically provide if it ran every hour of the year at its maximum expected output. Duke Power's nuclear units typically operate at capacity factors above 90%. The Company's largest coal units operate at capacity factors of about 80%. Intermediate units operate at capacity factors in the range of 35 to 80%, and peaking units below 5%.

Q. HOW DOES THE COMPANY DECIDE WHEN TO OPERATE EACH TYPE OF GENERATOR?

A. Each day, the Company selects the combination of company-owned generating units and available purchases that will reliably meet customer needs in the least cost manner. Lower cost units are operated first, with higher cost units added as load increases. Intraday adjustments are made to reflect changing conditions and purchase opportunities.

Q. PLEASE DESCRIBE HOW PURCHASES OF POWER FROM OTHERS FIT INTO THIS PROCESS.

A. The Company monitors the energy market, evaluating long-term, seasonal, monthly, weekly, daily and hourly purchase opportunities. For example, in making the daily decisions on which resources should be used to meet customer needs, the Company may purchase from others, whether from long-term capacity purchases that the Company has entered into or short-term spot market purchases to ensure it selects the most cost-effective, reliable options.

Q. PLEASE DESCRIBE THE RELATIVE COSTS OF THE VARIOUS FUELS USED BY DUKE POWER FOR ITS GENERATING UNITS.

A. Nuclear fuel is the least costly fuel for the Company with a cost of approximately 0.4 cents/kWh. Coal costs are approximately 1.9 to 2.8 cents/kWh depending on the generating plant. While the cost of natural gas and fuel oil are significantly higher, the fuel costs for these fuels is small compared to total fuel costs due to the limited need to call on our combustion turbines. The fuel cost of conventional hydroelectric generation is essentially zero. The cost of pumped storage hydroelectric generation is the fuel cost of the generating unit used to pump the water to the upper reservoir. Hydroelectric operation is limited by the amount of rainfall and water that can be drawn through the units in compliance with the Company's operational licenses.

Q. HOW MUCH OF DUKE POWER'S ENERGY CONSUMED IN THE REVIEW PERIOD WAS GENERATED BY EACH TYPE OF GENERATING UNIT?

A. During the review period, the energy produced by Duke Power's generation was as follows:

Fossil fuels	52%
Nuclear	47%
Hydro	1%

Q. MS. HAGER, PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S NUCLEAR GENERATING SYSTEM DURING THE PERIOD APRIL 2004 THROUGH JUNE 2005.

A. Hager Exhibit 1 sets forth the achieved nuclear capacity factor for the period April 2004 through June 2005 based on the criteria set forth in Section 58-27-865, Code of Laws of South Carolina. The statute states in pertinent part as follows:

> There shall be a rebuttable presumption that an electrical utility made every reasonable effort to minimize cost associated with the operation of its nuclear generation facility or system, as applicable, if the utility achieved a net capacity factor of ninety-two and one-half percent or higher during the period under review. The calculation of the net capacity factor shall exclude reasonable outage time....

As shown on page 1 of Hager Exhibit 1, Duke Power achieved a net nuclear capacity factor, excluding reasonable outage time, of 102.53% for the current period. This capacity factor is well above the 92.5% set forth in S.C. Code § 58-27-865.

Considering the refueling requirements, maintenance requirements, Nuclear Regulatory Commission (NRC) operating requirements, and the complexity of operating nuclear generating units, the Company's system will almost always have the equivalent of at least one nuclear unit out of service. Pages 2 and 3 of Hager Exhibit 1 show the dates of and explanations for actual and forecast outages of a week or more in duration.

Q. PLEASE DISCUSS THE PERFORMANCE OF DUKE POWER'S FOSSIL GENERATING SYSTEM.

A. Duke Power's fossil generating system consists of coal-fired units and combustion turbines which can burn either natural gas or fuel oil. In the review period, the Company's coal-fired generating plants provided approximately 52% of Duke Power's total generation. In 2004, the heat rate for the coal system was 9,466

BTU/kWh. Heat rate is defined as a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as BTUs per kilowatt-hour (Btu/kwh). A low heat rate indicates an efficient generating system that uses less heat energy from fuel to generate electrical energy. Duke Power has consistently been an industry leader in achieving low heat rates. Duke Power's Marshall Steam Station and Belews Creek Steam Station ranked as the country's first and fifth most energy efficient coal-fired generators in the most recent Electric Light and Power magazine ratings.

Duke Power's combustion turbines were available for use as needed but were required to run only infrequently due to the mild weather in the review period.

Q. PLEASE DESCRIBE HOW DUKE POWER INCLUDED FUEL COSTS RELATED TO PURCHASES IN ITS FUEL EXPENSES FOR THE REVIEW PERIOD.

A. Section 58-27-865(A) of the 1976 Code of Laws of South Carolina sets forth the definition of fuel costs related to purchased power as follows:

> (A)(1) The words 'fuel cost' as used in this section include the cost of fuel, fuel costs related to purchased power, and the cost of SO2 emission allowances as used and must be reduced by the net proceed of any sales of SO2 emission allowances by the utility.
>
> (2) In order to clarify the intent of this section, 'fuel costs related to purchased power', as used in subsection (A)(1) shall include:
>
> (a) costs of firm generation capacity purchases, which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels; 'costs of firm generation capacity purchases' include the total delivered costs of firm generation capacity purchased and shall exclude generation capacity reservation charges, generation capacity option charges, and any other capacity charges;
>
> (b) the total delivered cost of economy purchases of electric power including, but not limited to, transmission charges; 'economy purchases' are defined as purchases made to displace higher cost generation, at a price which is less than the purchasing utility's avoided variable costs for the generation of an equivalent amount of electric power.

In accordance with the statute, the Company used the avoided cost method to determine the fuel component of purchases of power for Duke Power's native load customers (retail customers and wholesale customers such as municipalities for whom Duke Power supplies generation capacity and energy). Under this methodology, the Company determines the costs it would have incurred in the absence of the purchase. This cost is determined by use of a model that identifies the incremental cost of the unit that would have been dispatched in the absence of the purchase and compares that cost to the cost of the purchase. The incremental cost includes the fuel and certain variable operation and maintenance costs. The Company includes in fuel costs the lower of the cost Duke Power would have incurred or the cost of the energy purchase. Duke Power's customers thereby are ensured of receiving the benefit of purchased power.

Q. MS. HAGER, PLEASE DESCRIBE HOW NUCLEAR COSTS ARE INCLUDED IN THE COMPANY'S FUEL EXPENSES.

A. The cost of each fuel assembly is determined when the fuel is loaded in the reactor. The costs include yellowcake (uranium), conversion, enrichment and fabrication. An estimate of the energy content of each fuel assembly is also made. Nuclear fuel expenses for each month are based on the energy output in units of millions BTUs (MBTUs) of each fuel assembly in the core and Department of Energy 'High Level Waste' and 'Decontamination and Decommissioning Fund' fees. A cost per MBTU is determined by dividing the cost of the assembly by its expected energy output. Each month a calculation of the MBTU output of an assembly is priced at its cost per MBTU.

During the life of a fuel assembly, the expected energy output may change as a result of actual plant operations. When this occurs, changes are made in the

cost per MBTU for the remaining energy output of the assembly. New fuel assembly orders are planned for cycle lengths of approximately eighteen months. The length of a cycle is the duration of time between when a unit starts up after refueling and when it starts up after its next refueling. During a refueling outage, approximately one-third of the fuel in the reactor is replaced.

Q MS. HAGER, CAN YOU EXPLAIN HOW COAL COSTS ARE INCLUDED IN THE COMPANY'S FUEL EXPENSES?

A. All of the Company's coal is delivered by rail. As coal is received at each plant, it is weighed and sampled for quality verifications. Subsequently, the purchasing department compares the weight, price and quality with the purchase order and railroad waybill. Purchasing personnel make adjustments to the cost of coal purchased in those cases where the quality of the coal received varies from contract specifications for British Thermal Unit (BTU), ash, and sulfur content.

Duke Power also performs moisture and BTU tests as the coal is delivered to the coal bunkers for each boiler. BTU tests measure the energy content of the coal. To the extent that the moisture content of the coal burned differs from the moisture content of coal purchased, an adjustment is subsequently made to the inventory tonnage. Wet coal weighs more than dry coal and without the moisture adjustment, tons burned would be overstated and inventory would be understated.

Duke Power calculates coal costs charged to fuel expense on an individual plant basis. The expense charge is the product of the tons of coal conveyed to the bunkers for a generating unit during the month multiplied by the average cost of the coal. The number of tons is determined by using scales located on the conveyor belt running to the unit's coal bunkers. The average cost reflects the total cost of coal on hand as of the beginning of the month, computed using the

moving average inventory method, plus the cost of coal delivered to the plant during the month. Duke Power determines the cost of coal based upon the invoice for the coal and the freight bill, and does not include any non-fuel cost or coal handling cost at the generating station.

Duke Power conducts annual physical inventories of coal piles through aerial surveys. Duke Power made an adjustment to book inventory for coal in December 2004 based on an aerial survey conducted in November 2004.

Q. WHAT IS SHOWN ON HAGER EXHIBIT 2?

A. Hager Exhibit 2 is a summary of nuclear fuel purchases and inventory, as discussed above. The average price for uranium during the review period was $2.48 per pound higher than the average price in the prior review period. This approximately 22% increase is due to increased price of spot market purchases and increases in prices under Duke's long term contracts that are linked to published spot market indices. The exhibit also shows uranium (or uranium equivalents) at the beginning and end of this reporting period. Inventory levels fluctuate over time due to the number of times nuclear fuel is loaded into the reactors and the uranium requirements of such reloads. Therefore, future uranium inventories at any given point in time may be higher or lower than the current level depending on the associated timing of future reloading requirements.

Q. MS. HAGER, WHAT DOES EXHIBIT 3 SHOW?

A. Hager Exhibit 3 sets forth the total system actual fuel costs (as burned) that the Company incurred from April 2004 through June 2005. This exhibit also shows fuel costs by type of generation and total megawatt hours (MWH) generated during this period. The monthly fluctuations in total fuel cost during this period are

primarily due to refueling and other outages at the nuclear stations, weather sensitive sales and the availability of hydroelectric generation.

Q. WHAT IS THE MAGNITUDE OF THE COMPANY'S FUEL COST COMPARED TO THE TOTAL COST OF SERVICE?

A. Fuel costs continue to be the largest cost item Duke Power incurs in providing electric service. For the twelve months ended May 2005, fuel and the fuel component of purchased power represented approximately 22% of the Company's total revenue. Of fuel costs, coal costs are the largest component and during the period April 2004 through June 2005 comprised approximately 78% of the costs of the Company's fuel burned.

Q. MS. HAGER, WHAT CHANGES HAVE OCURRED IN THE UNIT COST OF FUEL DURING RECENT REPORTING PERIODS?

A. Hager Exhibits 4A and 4B graphically portray the "as burned" cost of both coal and nuclear fuel in cents per MBTU for the twelve month periods ending January 2003 through June 2005. As Exhibit 4A shows, coal costs increased during the period as testified to by Witness Batson. Exhibit 4B shows that nuclear fuel costs have been flat. The costs incurred by Duke Power for the other fossil fuels used by the Company, natural gas and fuel oil, are a very small percentage of the total fuel costs. The costs incurred during the review period for these fuels were approximately $24 million, or less than 2% of the Company's total fuel expense for the year.

Duke Power expects its composite cost of fuel to increase. While the unit costs of nuclear fuel have shown little volatility in the recent past, the Company's future KWH growth will be met primarily from the Company's coal generating units,

and the cost of coal, which is about three times the cost of nuclear fuel, appears to be on an upward trend.

Q. WHAT DOES HAGER EXHIBIT 5 SHOW?

A. Hager Exhibit 5 graphically shows generation by type for the current and projected periods as well as three prior periods. As the Exhibit demonstrates, nuclear and fossil fuel account for approximately 99% of the Company's total generation.

Q. MS. HAGER, DO YOU BELIEVE THE COMPANY'S ACTUAL FUEL COSTS INCURRED DURING THE PERIOD APRIL 2004 THROUGH JUNE 2005 WERE REASONABLE?

A. Yes. I believe the costs are reasonable and that Duke Power has demonstrated that it meets the criteria set forth in Section 58-27-865(F) of the Code of Laws of South Carolina. These costs also reflect the Company's continuing efforts to maintain reliable service and an economical generation mix, thereby minimizing the total cost of providing service to our South Carolina retail customers.

Q. WHAT HAS BEEN THE COMPANY'S FUEL RECOVERY EXPERIENCE DURING THE APRIL 2004 THROUGH JUNE 2005 REVIEW PERIOD?

A. Hager Exhibit 6 shows the actual fuel costs incurred for the period April 2004 through June 2005, the estimated fuel costs for July 2005 through September 2005, and the over-recovery carried forward at the beginning of the period. This exhibit compares the fuel costs incurred with the revenues collected applying the applicable fuel rate of 1.150¢/KWH for the period April 2004 through September 2005. The Company started the period over-recovered by $12,106,000 as shown on line 12.

By Order No. 2004-603 in Docket No. 2004-324-E, the Commission approved Duke Power's proposal to forego and write-off recovery of up to $16

million of under-recovered fuel costs through September 2005. The Company made the proposal in an effort to mitigate anticipated under-recovery of fuel costs during the 2005 summer months as Duke Power transitioned to the new hearing schedule. As shown on line 12 of Hager Exhibit 6, as of June 2005, the Company had written off approximately $11 million in under-recovery of fuel costs.

Q. WHAT IS THE BASIS FOR ESTIMATING FUEL COSTS AS SHOWN ON HAGER EXHIBITS 6 AND 7?

A. Duke Power developed the projections shown on Hager Exhibits 6 and 7 based on the latest information available to the Company. The projected kWh sales are from the Company's 2005 sales forecast. Projected nuclear generation reflects planned outages, which include refueling outages at four units. The projection of fuel costs are based on a 97% capacity factor for the nuclear units while they are running. The Company's most recent nuclear fuel cost estimate was used to determine projected nuclear fuel expense. Estimated hydroelectric generation for the period is based on median generation for the period 1974 - 2004. The Company estimates fuel costs of energy purchases based on historical purchase quantities and price. Oil and gas fuel costs and generation are based on a three year average. The Company assumes that the remainder of the customers' energy needs are served from coal-fired units. The projected price for coal contracts is based on the price of coal contracts that will be in place during the projection period along with the current market price for coal needs beyond the currently contracted amounts.

Q. HAVE THERE BEEN ANY ADJUSTMENTS TO THE ESTIMATED FUEL COST FOR THE PROJECTED PERIOD IN ADDITION TO THE PROCESS DESCRIBED ABOVE?

A. Yes. The projected period includes adjustments to reduce fuel expense related to two recent settlements. Estimated fossil fuel expense for July 2005 has been reduced by [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] dollars as a result of a settlement between the Company and Norfolk Southern Railway Company. The litigation and settlement are described further by Witness Batson. Additionally, estimated nuclear fuel expense for July 2005 has been reduced by approximately [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] as the result of a settlement between the Department of Energy ("DOE") and nine utility companies including Duke Power of litigation related to enrichment services for nuclear fuel. The utilities claimed that the DOE had overcharged them for enrichment services that they purchased over a period of time under contracts with the DOE. The reduction to nuclear fuel expense is net of the Catawba Joint Owner's approximately [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] share of the settlement. Although Duke Power incurred litigation expenses on behalf of its customers to achieve these settlements, the Company has elected to offset fuel expenses with the total proceeds of the settlement (less the Catawba Joint Owner's Share) in order to mitigate the impact of rising fuel costs on its South Carolina customers.

After factoring in the impact of these settlements, Duke Power estimates that by September 30, 2005, the Company will be under-recovered in South Carolina by approximately $22 million. Line 12 of Hager Exhibit 6 shows the write-off of an additional $5 million in under-recovery of fuel costs in September 2005 for a total write-off of $16 million as approved in Docket No. 20004-324-E by Order No. 2004-603. As a result of this additional write-off, the Company is projecting an

under-recovery at the end of the current billing period (September 2005) of $17,137,000.

Q. MS. HAGER, WHAT IS THE COST OF FUEL THE COMPANY PROJECTS FOR RECOVERY DURING THE PERIOD OCTOBER 2005 THROUGH SEPTEMBER 2006?

A. Hager Exhibit 7 sets forth projected fuel costs for the period October 2005 through September 2006. As shown on line 7, the fuel cost estimated for recovery during this period is 1.5036¢/KWH. After adjusting for the cumulative under-recovery, the adjusted fuel cost is 1.5802¢/KWH. In addition, the Company is proposing a decrement of 0.1732¢/KWH related to deferred income tax liability as testified to by Witness Jacobs. The Company seeks Commission approval for a proposed fuel factor of 1.5802¢/KWH and the deferred tax decrement of 0.1732¢/KWH resulting in a net billing factor of 1.4070¢/KWH.

As stated by Witness Jacobs, Duke Power will exclude the deferred tax decrement in calculating its under- or over-recovery for the next test period. Based on our estimate, the proposed fuel factor would result in the Company being neither under- or over-recovered in its fuel cost at the end of the billing period in September 2006.

Q. MS. HAGER, DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DUKE POWER COMPANY
SOUTH CAROLINA FUEL CLAUSE
2005 ANNUAL FUEL HEARING
NUCLEAR PLANT PERFORMANCE
CAPACITY FACTOR 4/04 - 6/05

1	Nuclear System Actual Net Generation During Test Period	69,158,837	MWH
2	Total Number of Hours During Test Period	10,943	
3	Nuclear System MDC During Test Period	6,996.0	MW
4	Reasonable Nuclear System Reductions	9,102,163	MWH
5	Nuclear System Capacity Factor $\left[\frac{1}{((2*3)-4)}\right]*100$	102.53	%

Hager Exhibit 1
Page 1 of 3

DUKE POWER COMPANY
SOUTH CAROLINA FUEL CLAUSE
2005 ANNUAL FUEL HEARING
NUCLEAR PLANT PERFORMANCE

Nuclear Outages Lasting One Week Or More - Current Period

Unit	Date of Outage	Explanation of Outage
Oconee 1	04/08/05-05/15/05	Scheduled Refueling - EOC 22
Oconee 2	03/20/04-06/05/04	Scheduled Refueling - EOC 20/Steam Generator and Reactor Vessel Head Replacement Outage
Oconee 2	06/05/04-06/13/04	Outage delay due to "2A" reactor building cooling unit fan assembly failure
Oconee 3	10/09/04-01/02/05	Scheduled Refueling - EOC 21/Steam Generator Replacement Outage
McGuire 1	03/06/04-04/06/04	Scheduled Refueling - EOC 16
McGuire 1	10/18/04-11/11/04	Repair 1B steam generator instrument line leak
McGuire 2	03/05/05-04/12/05	Scheduled Refueling - EOC 16
Catawba 1	05/07/05-06/06/05	Scheduled Refueling - EOC 15
Catawba 2	09/11/04-10/24/04	Scheduled Refueling - EOC 13

DUKE POWER COMPANY
SOUTH CAROLINA FUEL CLAUSE
2005 ANNUAL FUEL HEARING
NUCLEAR PLANT PERFORMANCE

Nuclear Outages Lasting One Week Or More - Forecast Period

Pursuant to 26 S.C. Code Ann. Regs. 103-804(Y)(2), this page 3 of Hager Exhibit 1 is redacted in its entirety with the exception of the heading set forth above.

NUCLEAR FUEL PURCHASES
APRIL 2004 - JUNE 2005

URANIUM		
	Pounds Purchased	4,718,877
	Avg. Price/Pound	$13.70

NUCLEAR FUEL INVENTORY

	03/31/04	06/30/05
URANIUM (POUNDS)	1,797,723	2,546,865

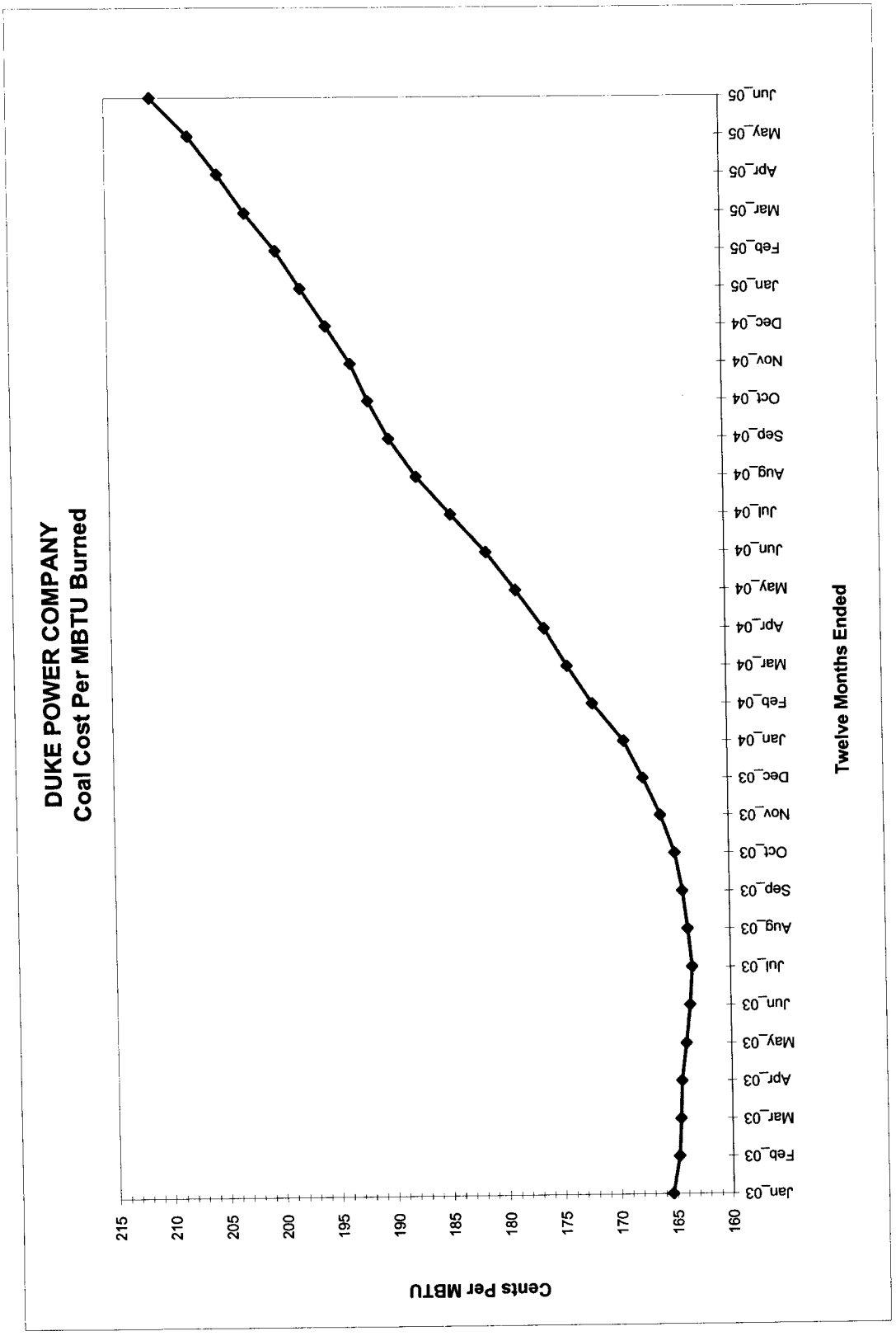
Hager Exhibit 2

DUKE POWER COMPANY
SOUTH CAROLINA FUEL CLAUSE
2005 ANNUAL FUEL HEARING
TOTAL COMPANY FUEL COST
$000

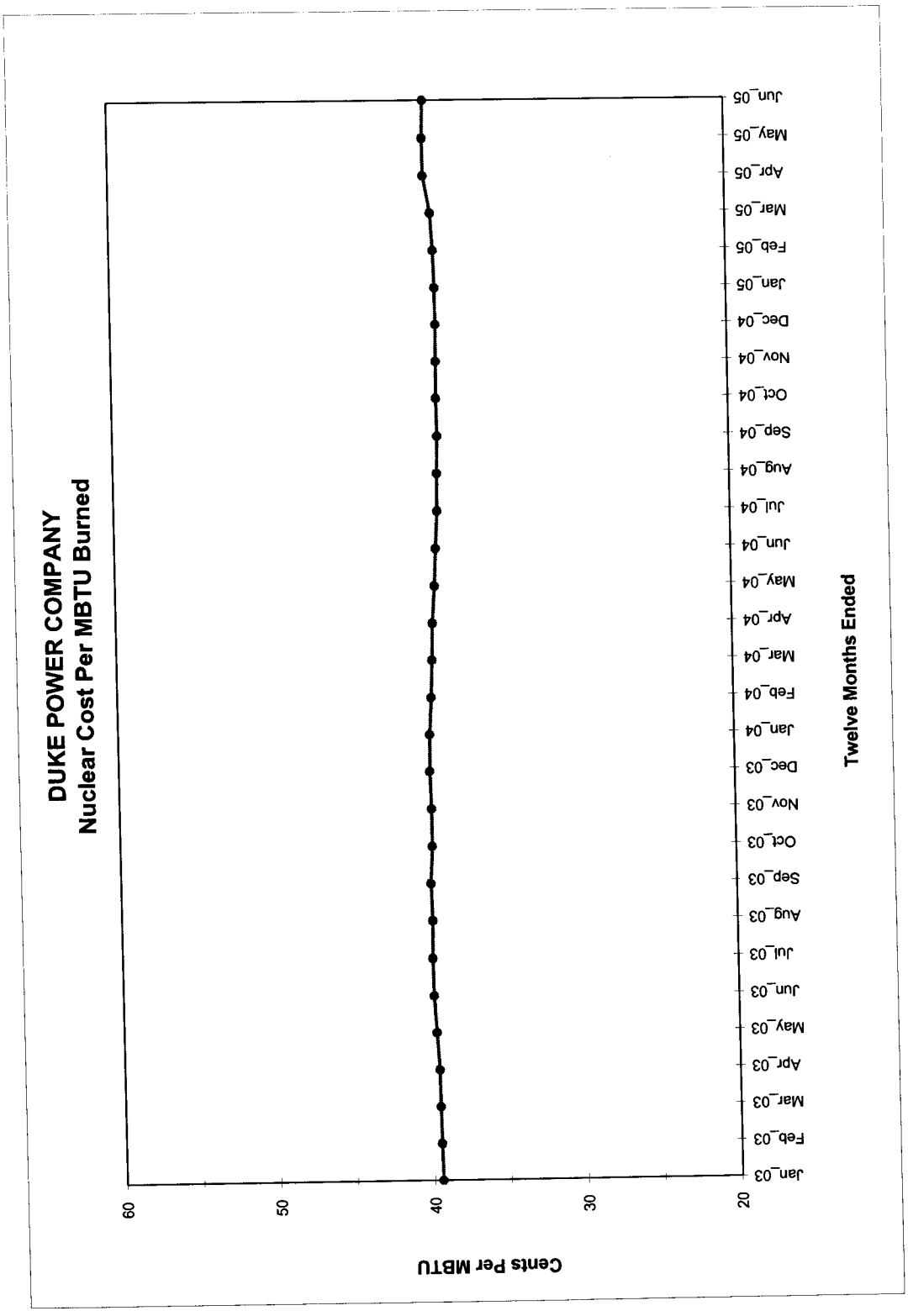
Line No.	Description	Mo. Avg. 12Mo. 3/04	April 2004	May 2004	June 2004	July 2004	Aug. 2004	Sept. 2004	Oct. 2004	Nov. 2004	Dec. 2004	Jan. 2005	Feb. 2005	March 2005	April 2005	May 2005	June 2005	Mo. Avg. 15Mo. 6/05
1	Coal	$61,293	$61,817	$69,025	$71,263	$84,247	$79,064	$59,820	$62,606	$56,329	$63,813	$72,027	$69,448	$79,428	$73,350	$75,405	$90,678	$71,221
2	Emission Allowance Exp.	$574	$720	$823	$836	$656	$545	$417	$450	$404	$466	$308	$300	$241	$361	$561	$1,169	$550
3	Oil	917	574	4,722	767	548	1,032	896	672	958	1,614	1,196	717	957	747	1,207	826	1,162
4	Gas	108	10	4,689	344	97	1,064	918	(1,647)	47	79	1,042	(522)	564	(997)	657	344	446
5	Nuclear	13,236	10,977	12,676	13,201	15,009	15,249	14,380	11,980	11,576	13,153	15,091	13,803	12,889	12,722	13,512	14,258	13,365
6	Total	$76,128	$74,098	$91,935	$86,411	$100,557	$96,954	$76,431	$74,061	$69,314	$79,125	$89,664	$83,746	$94,079	$86,183	$91,342	$107,275	$86,744
7	MWH Gen.	6,984,809	6,133,960	6,998,949	7,110,991	8,176,220	7,772,810	6,611,077	6,185,429	5,797,101	6,723,760	7,587,739	6,944,285	6,866,959	6,147,097	6,959,863	7,789,617	6,920,390

Hager Exhibit 3

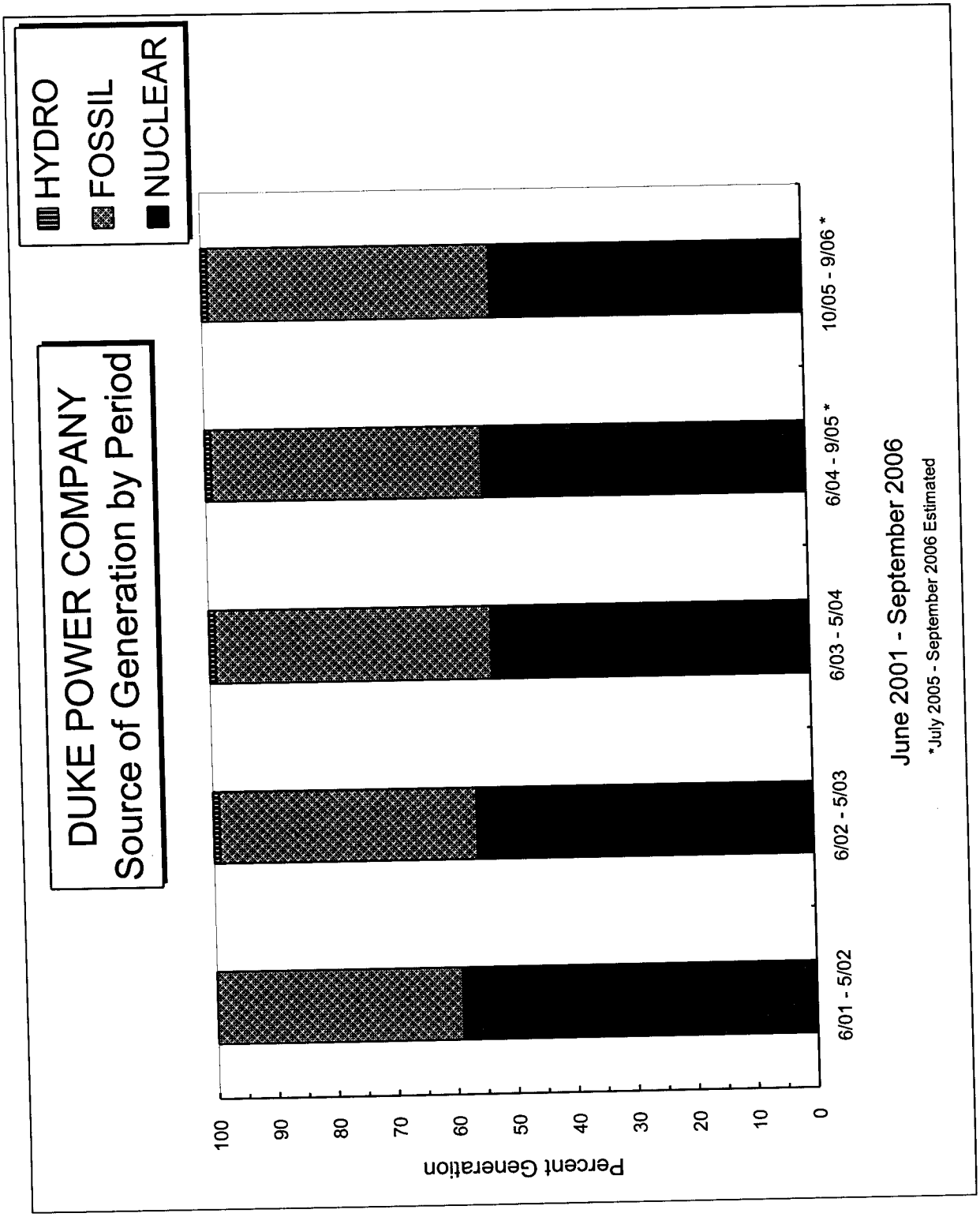
Hager Exhibit 4A



Hager Exhibit 4B



Hager Exhibit 5



DUKE POWER COMPANY
SOUTH CAROLINA FUEL CLAUSE
2005 ANNUAL FUEL HEARING
CURRENT PERIOD FUEL COSTS INCURRED
$000

Line No.	Item	April 2004	May 2004	June 2004	July 2004	Aug. 2004	Sept. 2004	Oct. 2004	Nov. 2004	Dec. 2004	Jan. 2005	Feb. 2005	March 2005	April 2005	May 2005	June 2005	Estimated July 2005 (A)(B)	Estimated Aug. 2005	Estimated Sept. 2005
1	Fossil Fuel	$62,400	$78,435	$72,374	$84,892	$81,161	$61,634	$61,631	$57,334	$65,506	$74,265	$69,644	$80,948	$73,099	$77,268	$91,848	$116,740	$130,210	$103,560
2	Emission Allowance Exp.	720	823	836	656	545	417	450	404	466	308	301	241	361	561	1,169	551	551	551
3	Nuclear Fuel	10,977	12,676	13,201	15,009	15,249	14,379	11,980	11,576	13,153	15,091	13,803	12,889	12,722	13,512	14,258	3,321	15,024	13,255
4	Fuel In Purchases	4,456	8,211	13,227	4,999	4,445	2,520	2,848	3,527	6,216	2,113	1,496	4,455	2,192	5,298	2,334	4,368	4,368	4,368
5	Fuel In Intersystem Sales	13,617	8,278	5,956	12,071	9,292	4,368	588	5,092	7,286	18,459	22,808	20,989	22,516	13,463	20,671	19,752	19,752	19,752
6	Total Costs	$64,936	$91,867	$93,682	$93,485	$92,108	$74,582	$76,321	$67,749	$78,055	$73,318	$62,436	$77,544	$65,858	$83,176	$88,938	$105,228	$130,401	$101,982
7	MWH Sales	6,006,088	5,714,641	6,981,737	6,968,944	7,194,367	6,977,080	5,814,932	5,819,528	6,057,959	6,601,294	6,352,976	6,360,977	5,759,869	5,722,160	6,593,837	7,719,045	8,083,192	7,335,256
8	Fuel Cost ¢/KWH	1.0812	1.6076	1.3418	1.3415	1.2803	1.0690	1.3125	1.1642	1.2885	1.1107	0.9828	1.2191	1.1434	1.4536	1.3488	1.3632	1.6132	1.3903
9	¢/KWH Billed	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500
10	SC Retail MWH Sales	1,671,896	1,632,881	1,936,215	1,941,395	2,001,791	1,935,473	1,625,658	1,664,218	1,710,561	1,803,088	1,789,530	1,704,461	1,633,990	1,628,822	1,858,972	2,090,800	2,167,462	2,080,211
11	$ (Over) Under	($1,150)	$7,472	$3,714	$3,718	$2,608	($1,568)	$2,642	$236	$2,369	($709)	($2,991)	$1,178	($108)	$4,945	$3,696	$4,458	$10,040	$4,999
12	Prior Period (Over) Under	($12,106)		$681						($6,718)			$2,698	($1,057)		($6,880)			(5,030)
13	Cumulative (Over) Under	($13,256)	($5,784)	($1,389)	$2,329	$4,937	$3,369	$6,011	$6,247	$1,898	$1,189	($1,802)	$2,074	$909	$5,854	$2,670	$7,128	$17,168	$17,137

NOTES:
(A) Fossil fuel includes a reduction of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] as a result of a settlement between the Company and Norfolk Southern Railway Company.
(B) Nuclear fuel includes a reduction of [BEGIN CONFIDENTIAL] [END CONFIDENTIAL] as a result of a settlement between nine utilities, including Duke Power, and the Department of Energy.

Hager Exhibit 6

DUKE POWER COMPANY
SOUTH CAROLINA FUEL CLAUSE
2005 ANNUAL FUEL HEARING
PROJECTED FUEL COST 10/05 - 9/06
$000

Line No.	Item	Oct. 2005	Nov. 2005	Dec. 2005	Jan. 2006	Feb. 2006	March 2006	April 2006	May 2006	June 2006	July 2006	Aug. 2006	Sept. 2006	Total
1	Fossil Fuel	$92,228	$91,861	$94,122	$107,439	$90,495	$87,671	$82,766	$98,786	$109,937	$135,171	$133,204	$106,782	$1,230,462
2	Nuclear Fuel	12,666	13,034	15,024	15,447	14,042	15,277	14,693	13,324	14,967	15,447	15,447	13,511	172,879
3	Fuel In Purchases	4,368	4,368	4,368	4,368	4,368	4,368	4,368	4,368	4,368	4,368	4,368	4,368	52,416
4	Fuel In Intersystem Sales	19,752	19,752	19,752	19,752	19,752	19,752	19,752	19,752	19,752	19,752	19,752	19,752	237,024
5	Total Fuel Costs	$89,510	$89,511	$93,762	$107,502	$89,153	$87,564	$82,075	$96,726	$109,520	$135,234	$133,267	$104,909	$1,218,733
6	Total MWH Sales	5,866,769	5,879,950	6,540,726	7,150,492	6,750,044	6,294,100	6,266,803	5,959,109	6,907,277	7,832,237	8,182,068	7,426,031	81,055,606
7	Fuel Costs Incurred ¢/kwh	1.5257	1.5223	1.4335	1.5034	1.3208	1.3912	1.3097	1.6232	1.5856	1.7266	1.6288	1.4127	1.5036
8	SC Retail MWH Sales	1,736,102	1,699,124	1,795,523	1,892,880	1,852,853	1,684,387	1,717,515	1,722,141	1,910,966	2,096,994	2,169,874	2,084,817	22,363,176
9	SC Fuel Costs	$26,488	$25,866	$25,739	$28,458	$24,472	$23,433	$22,494	$27,954	$30,300	$36,207	$35,343	$29,452	$336,253
10	(Over)/Under On Ex. 6													17,137
11	SC Fuel Costs													353,390
12	SC Fuel Cost ¢/kwh													1.5802
13	S.C. Retail Allocation of Revenue Requirement on True-up of Deferred Taxes on Property, Plant & Equipment													(38,738)
14	Deferred Tax Decrement Rider													(0.1732)
15	SC Factor in ¢/kwh													1.4070

Hager Exhibit 7

TESTIMONY OF
M. ELLIOTT BATSON

FOR

DUKE POWER

PSCSC Docket No. 2005–003-E

Q. PLEASE STATE YOUR NAME, ADDRESS AND POSITION WITH DUKE POWER.

A. My name is Elliott Batson and my business address is 526 South Church Street, Charlotte, North Carolina. I am Manager, Coal and Bulk Material Procurement of Duke Power, a division of Duke Energy Corporation ("Duke Power" or "the Company").

Q. STATE BRIEFLY YOUR EDUCATION, BUSINESS BACKGROUND AND PROFESSIONAL AFFILIATIONS.

A. I am a 1985 graduate of the University of South Carolina with a Bachelor of Science in Business Administration. I have been employed with Duke Power since 1986 and have worked in the Fossil Fuel Procurement area since 1990. I am a member of the North Carolina Coal Institute.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to furnish information relating to the Company's fossil fuel purchasing practices and costs for the period April 2004 through June 2005 and describe any changes forthcoming in 2005 and 2006.

Q. YOUR TESTIMONY INCLUDES EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. Each of these exhibits were prepared either by me or at my direction and under my supervision.

Q. MR. BATSON, CAN YOU PROVIDE A SUMMARY OF DUKE POWER'S FUEL

PROCUREMENT PRACTICES?

A. Yes. The Company continues to follow the same procurement practices that it has historically followed, and a summary of those practices can be found in Batson Exhibit 1.

Q. WHAT IS SHOWN ON BATSON EXHIBIT 2?

A. Batson Exhibit 2 is a statistical summary for each fossil fuel category for the period April, 2004 through June, 2005. The exhibit includes the quantities consumed, quantities purchased, and the 15-month weighted average purchase price for each fuel. Due to the different components which make up the total cost of coal, coal statistics are further broken down to show the average freight on board ("f.o.b.") mine cost, the transportation cost, and the delivered cost per million British Thermal Units ("BTUs").

The delivered cost per ton of coal increased from an average of $44.32 for the prior period to an average of $51.92 for the review period. This increase is due in general to the rising mine cost for coal. Specifically, coal prices were higher in the short term spot market in 2004 and 2005 compared to 2003 and significantly higher for contract coal purchased under contracts resulting from 2004 and 2005 Request for Proposals ("RFP"). As a result, the average mine price increased from $29.19 per ton of coal during the prior period to an average mine price of $35.07 per ton of coal during the review period. Central Appalachia coal market prices over the last 2 years have increased approximately 70% for contract deliveries and approximately 100% for shorter term spot deliveries. (See Batson Exhibit 3 for a summary of Central Appalachia market coal prices compared to average Duke Power coal costs.) Because Duke Power purchases a large percentage of its coal supply under 2 to 3 year contract arrangements, it has benefited from favorably priced coal contracts negotiated prior to the market increases, which resulted in significantly lower average coal mine costs in 2004 and 2005 as compared to prevailing market prices. The average transportation rate increased from $15.13 per ton to $16.85 per ton as

compared to the review period. This increase is due to escalating tariff rates and paying more fuel surcharges applied by the railroads as a result of increasing fuel oil prices.

The average oil cost for the review period increased almost $0.36/gal based on the previous 12 month period ending March 2004. This sharp increase is primarily attributed to strong economic growth, especially in China, during a period of flat world production. Duke Power consumed oil at an average of 1.1 million gallons per month during the review period which is comparable to the previous 12 month period ending March 2004. Average natural gas costs during the review period decreased slightly to $7.33/Mcf (per thousand cubic feet) when compared to the previous 12 month period ending March 2004. Duke Power consumed a greater volume of natural gas during the review period as compared to the prior period. Therefore, the decrease in the Company's average cost is more a function of fixed facility charges included in tariff rates Duke Power pays to local distribution companies being spread across greater volumes rather than a result of changes in the natural gas market.

Q. WHY HAVE COAL PRICES INCREASED?

A. Coal prices have increased significantly in the last couple of years primarily due to increasing domestic and international demand for Central Appalachia coal, limited production response to this increased demand, changing export market conditions for Central Appalachian coal, increasing mining operating costs, high natural gas prices and transportation complexities associated with alternative coal sources. Central Appalachian coal production declined 8% from 2002 to 2003 and increased only 1% from 2003 to 2004 despite strong demand. This limited production response is attributable to stringent environmental regulations and lengthy permitting requirements, and the necessity of mining in more difficult coal seams and conditions as the coal reserve base depletes. Increased demand for both steam and metallurgical coal in Asia and Europe has resulted

in increasing coal exports from Central Appalachia. Mining operating costs have increased due to higher petroleum costs, higher labor costs due to a shrinking skilled work force, higher steel prices, and tighter truck-hauling restrictions. Coal has followed natural gas price increases, as there is no competing fuel between coal and natural gas. As coal consumers start looking for alternative coal sources, options are limited due to the transportation constraints and complexities with moving coal longer and over non-traditional routes. These changes in transportation movements take considerable time to develop as railroads reallocate crews, equipment and upgrade infrastructure.

Q. WHAT CHANGES DO YOU SEE IN THE COMPANY'S COST OF COAL IN 2005 AND 2006?

A. As Duke Power's existing coal contracts expire, they will be replaced at market prices significantly higher today than what they have been in the last few years. Current market prices based on recent offers from several producers and forward coal prices as published by coal brokers indicate continued high pricing for Central Appalachia coal the balance of 2005 and first half of 2006. Current contract mine prices per ton are in the low to mid $50s for contract arrangements and in the mid to upper $50s for near term spot arrangements. As a result, the company's cost of coal will be increasing in 2005 and 2006 compared to 2004, although the average cost of coal will still be significantly below the projected market price for Central Appalachia coal. (See Batson Exhibit 3.) All of these new purchases will be competitively bid and negotiated in accordance with Duke Power's fuel purchasing practices described in Batson Exhibit 1.

Q. WHAT IS DUKE POWER DOING TO CONTROL ITS COAL COSTS?

A. Duke Power is pursuing several initiatives that will limit exposure to regional coal market price increases and help control and stabilize coal costs in general. Duke Power continues to develop a comprehensive coal procurement strategy that reduces the risk of

extreme price volatility seen in the market. Aspects of this strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations such that the Company is not faced with price changes for a significant percentage of purchases at any one time, pursuing contract extension options that provide flexibility to extend terms within some price collar and developing contract volume options providing Duke Power as the buyer with flexibility to increase or decrease volumes depending on market price. Duke Power's coal facilities are designed to operate using a typical Central Appalachia product of 12,000 BTU, 12% Ash and 1% sulfur; however, the Company is also developing the ability to burn non-Central Appalachia and non-traditional Central Appalachia coal in the future, primarily through coal blending, in order to take advantage of market opportunities to reduce coal costs as they come about. Duke Power, which typically issues on average two RFPs a year addressing longer term purchases, plans to issue RFPs in the future that address coal supply from throughout the United States and international sources. The Company will be evaluating operational plant issues associated with non-Central Appalachia and non-traditional Central Appalachia coal as well as working closely with the appropriate railroads to develop the needed infrastructure to deliver this coal. This evaluation will analyze current opportunities to diversify away from Central Appalachia and provide on-going flexibility to take advantage of purchase opportunities in changing domestic and international market conditions. Until this evaluation is complete, it is difficult to project the financial impact this flexibility may provide. An additional element of the Company's coal procurement strategy is to purchase synthetic fuel ("synfuel") from producers that have located synfuel production facilities at Duke Power plants and from the market generally.

Q. PLEASE EXPLAIN THESE SYNFUEL PURCHASE ARRANGEMENTS.

A. Under certain conditions, the Federal government provides tax credits for the production of synfuel. Duke Power has entered into agreements with two third parties that own synfuel production facilities that these suppliers have located at Duke Power's Belews Creek Steam Station and Marshall Steam Station, respectively. The Company purchases synfuel from these suppliers at prices which are discounted off of the cost of the feed-stock coal used to manufacture the synfuel. Duke Power acts as an agent for these suppliers in procuring and transporting feed-stock coal and in handling coal shipments. The price discounts increase with the volume of synfuel Duke Power purchases. Duke Power has no ownership interest in these synfuel facilities; however, through these arrangements it is able to achieve a reduction in fuel costs, which benefits Duke Power's customers. These arrangements could save over $20 million annually in fuel costs through the end of 2007. The Company may also purchase synfuel in the market at prices which may, depending upon market conditions, reflect a discount off the spot or contract price for coal.

Q. IN PREVIOUS YEAR'S FUEL ADJUSTMENT PROCEEDINGS, YOU TESTIFIED TO INCREASED COAL TRANSPORTATION COSTS AS A RESULT OF PENDING LITIGATION BEFORE THE SURFACE TRANSPORTATION BOARD ("STB"). WHAT IS THE STATUS OF THAT LITIGATION?

A. In order to contest a significant increase in the freight rates Norfolk Southern Railway Company ("Norfolk Southern") and CSX Transportation ("CSX") charged the Company beginning January 1, 2002, Duke Power filed complaints with the STB. On October 20, 2004 the STB issued a final decision in Duke Power's rate case complaints against Norfolk Southern and CSX in which the STB upheld all of the challenged rail transportation rates and did not establish any constraints on future rate increases. Subsequently, Duke Power initiated a "phasing" proceeding in both of the cases in which Duke Power sought to have

the sudden increases imposed gradually. Duke Power also appealed the STB's decisions to the United States Court of Appeals for the District of Columbia. However in June 2005, Duke Power reached settlement agreements and entered into new transportation contracts with both the Norfolk Southern and the CSX railroads. In connection with these agreements, Duke Power dismissed the complaints before the STB and all related proceedings including the "phasing" proceedings and the appeals. Specific terms of the settlements and new contracts are confidential. However, the Company can state that key terms of the agreements with Norfolk Southern include a lump sum cash payment which Duke Power has received and credited against fuel and a multi-year rail transportation contract with rates comparable to tariff rates the Company currently pays. Key terms of the agreements with CSX include a multi-year rail transportation contract with rates slightly below tariff rates the Company currently pays and the provision for new rates from non-Central Appalachia coal sources that provide enhanced coal supply flexibility. The primary benefit for reaching settlements and multi-year agreements with the railroads is the elimination of exposure to unlimited rate increases upon 20 days notice that existed for 7 of the Company's 8 coal plants while Duke Power was paying tariff rates.

Q. WHAT IS SHOWN ON BATSON EXHIBIT 4?

A. Batson Exhibit 4 shows inventories for coal and oil at the beginning and end of this reporting period. Coal inventories increased from 1,575,521 tons as of March 31, 2004 to 2,392,767 tons as of June 30, 2005. This increase is due to improved railroad service and a more moderate coal burn in 2005 compared to 2004. This increase brings the Company's system level of inventory back in line with the target level. Duke Power expects to maintain appropriate inventory to support consumption requirements and will continue to closely monitor coal supplier and railroad performance.

Oil inventories remained the same with the previous March 2004 ending inventory.

Purchases equaled consumption during the April 2004 through June 2005 period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Duke Power Fossil Fuel Procurement Practices

The Company's fossil fuel procurement practices are summarized below.

Coal

- Near and long-term consumption forecasts are computed based on factors such as: load projections, fleet maintenance and availability schedules, coal quality and cost, environmental permit and emissions considerations, wholesale energy imports and exports.
- Station and system inventory targets are determined and designed to provide: reliability, insulation from short-term market volatility, and sensitivity to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to ascertain additional needs.
- All qualified suppliers are invited to make proposals to satisfy any additional or future contract needs.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, quality, transportation, reliability and flexibility.
- Spot market solicitations are conducted on an ongoing basis to supplement the contract structure.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on weights registered by Duke's scale system and coal quality analysis as conducted by Duke Power's Central Fuels Laboratory.

Natural Gas

- Near and long-term consumption forecasts are generated by the same system that produces coal estimates. Gas is burned exclusively in peaking assets – combustion turbines.
- Gas is not locally inventoried, but rather scheduled and delivered via pipeline on a daily basis. Oil is burned when gas is not economically available.
- In response to annual solicitation, suppliers submit proposals to provide bundled supply service to peaking facilities. This service consists of the commodity (gas), its transportation (pipeline), storage, and balancing services.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, responsiveness, reliability, and best operational fit.

Fuel Oil

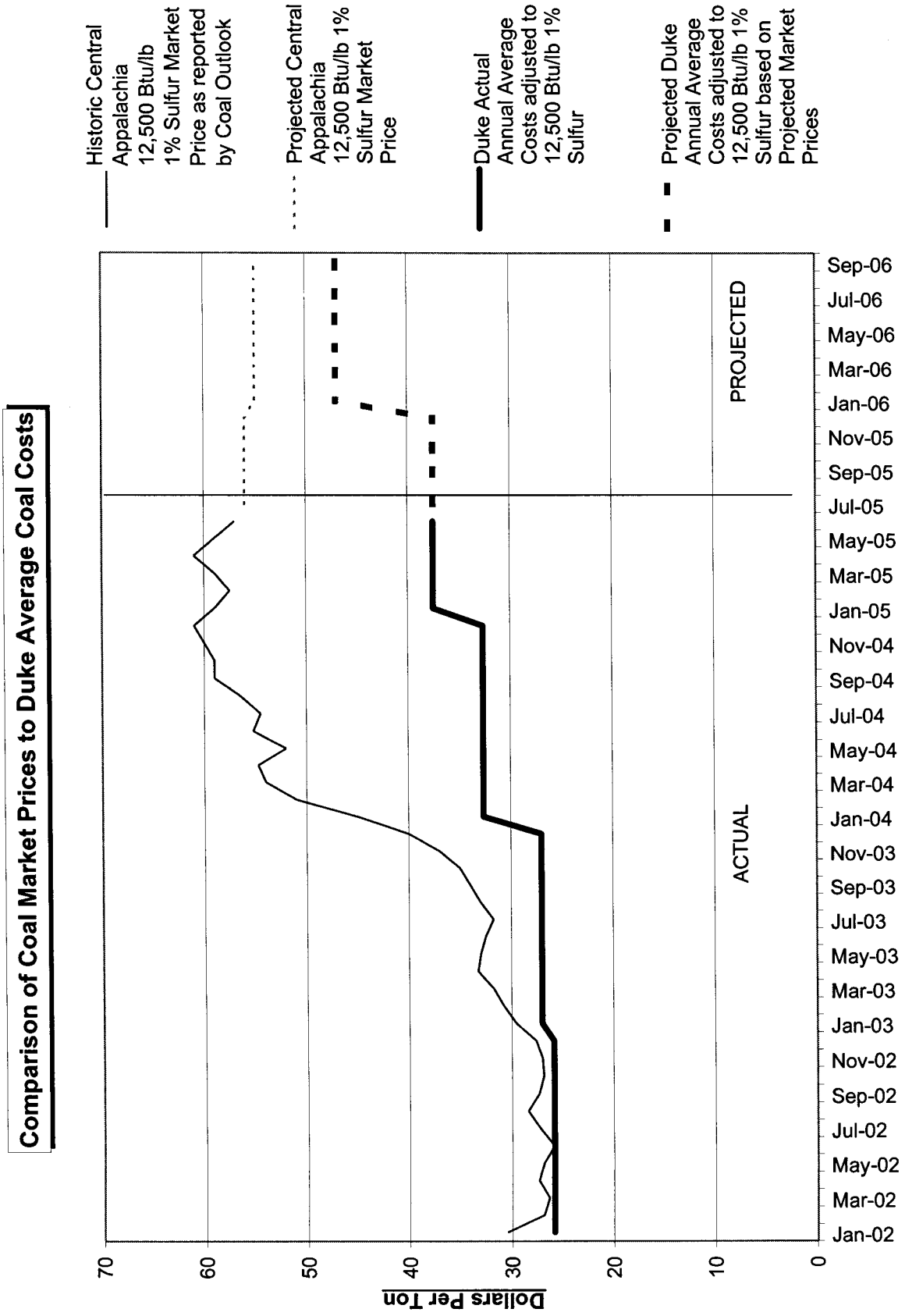
- Consumption forecasts are generated by the same system that produces coal estimates. No. 2 diesel is burned for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All diesel fuel is moved via pipeline to terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, Duke relies on a combination of inventory and reliable suppliers who are responsive and can access multiple terminals. Diesel is replaced on an "as needed basis" as called for by station personnel with guidance from fuel procurement staff.
- Formal solicitation for supply is conducted annually. Contracts are awarded based on the lowest evaluated offer with special value on suppliers demonstrated ability to move large volumes of fuel with minimal notice.

BATSON EXHIBIT 2

FUEL PURCHASES AND CONSUMPTION
APRIL 2004 - JUNE 2005

COAL		
	Tons Burned	21,012,078
	Tons Purchased	21,767,474
	Avg. Mine Price/Ton	$35.07
	Avg. Freight Price/Ton	$16.85
	Avg. Delivered Price/Ton	$51.92
	Avg. Delivered Price/MBTU	$2.1167
OIL		
	Gallons Consumed	15,782,867
	Gallons Purchased	16,240,032
	Avg. Price/Gallon Purchased	$1.2430
NATURAL GAS		
	Mcf. Purchased	898,969
	Avg. Price/Mcf.	$7.33

Batson Exhibit 3



BATSON EXHIBIT 4

FUEL INVENTORIES

	03/31/04	06/30/05
COAL (TONS)	1,575,521	2,392,767
#2 OIL (GALLONS)	17,885,201	17,614,923

TESTIMONY OF
DWIGHT L. JACOBS

FOR

DUKE POWER

PSCSC Docket No. 2005-003-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Dwight L. Jacobs. My business address is 526 South Church Street, Charlotte, North Carolina. I am Vice President and Controller for Duke Power, a division of Duke Energy Corporation ("Duke Power" or "the Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE POWER?

A. As the Controller, I am responsible for the accuracy and timeliness of the financial results of Duke Power.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in accounting in 1987 from the University of North Carolina at Chapel Hill. I became a certified public accountant in North Carolina in 1990. My background includes 14 years with Arthur Andersen, where I was promoted to manager in 1993 and promoted to partner in 2000. I joined Duke Energy in 2002 as managing director of corporate accounting and reporting, and was promoted to Vice President and Controller of Duke Power in July 2004. I am a member of the Edison Electric Institute's Accounting Standards Committee, American Institute of Certified Public Accountants and N.C. Association of Certified Public Accountants.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain the Company's request to include a decrement of 0.1732¢ per KWH related to an accumulated deferred income tax liability. This

decrement is set forth on Jacobs Exhibit 1.

Q. PLEASE EXPLAIN THE DECREMENT REFLECTED ON JACOBS EXHIBIT 1.

A. Duke Power is proposing a decrement of 0.1732¢ per KWH related to an accumulated deferred income tax liability. This excess liability was accumulated over decades in anticipation of income tax liabilities that were not ultimately realized. The Company determined that it accumulated approximately $153 million (total system) in revenue requirement related to excess deferred income taxes and proposes to flow the South Carolina retail portion to customers through the fuel clause factor for the October 1, 2005 through September 30, 2006 billing period. The South Carolina retail allocation of the liability is $38.7 million, resulting in a decrement of 0.1732¢ per KWH. The Company is seeking Commission approval in this proceeding for this accounting treatment in its order approving the fuel factor to be billed for the period October 1, 2005 through September 30, 2006.

Q. PLEASE EXPLAIN THE NATURE OF THE COMPANY'S DEFERRED INCOME TAX LIABILITY.

A. The deferred income tax liability for Duke Power is primarily driven by depreciation of property, plant and equipment under tax laws being faster than depreciation under generally accepted accounting principles. Corporations are permitted to accelerate depreciation for tax purposes in order to stimulate investment. The difference between the book depreciation and the tax depreciation results in a deferral of income taxes owed on annual earnings. Because the income tax liability will ultimately be paid at a later time, Duke Power, like other corporations, must record the deferred income tax liability on its books.

Q. HOW DID THIS OVER-ACCRUAL OCCUR AND HOW DID THE COMPANY DISCOVER IT?

A. According to Duke Power's best determination, the over-accrual occurred in the tax software used by the Company. It occurred over many years in small increments. The output from the tax software overstated the difference between book and tax depreciation resulting in an over-accrual of deferred income taxes. The Company discovered the over-accrual in connection with an audit by Deloitte and Touche, the Company's external auditor. Duke Power determined that the Company's Accumulated Deferred Income Taxes were over accrued by $93 million. Prior to the release of the Company's 2002 SEC Form 10K in March of 2003, it reduced the accumulated deferred income taxes on its books by $93 million and recognized a liability at a revenue requirement level of $153 million in a deferred credit account.

Q. WHY IS DUKE POWER SEEKING APPROVAL TO FLOW THE REVENUE REQUIREMENT RELATED TO THIS EXCESS DEFERRED INCOME TAX LIABILITY TO CUSTOMERS IN THIS PROCEEDING?

A. Once the Company determined that the accumulated deferred income tax liability was overstated, generally accepted accounting principles require that the excess amount be reversed. Typically this is accomplished by reducing income tax expense for the over-accrued amount in the period it was determined. As an alternative, in order to mitigate the impact of rising fuel costs on its South Carolina customers, Duke Power has elected to seek Commission approval to flow the revenue requirement related to this excess deferred tax liability to customers in this proceeding.

Q. HOW DID DUKE POWER CALCULATE THE SOUTH CAROLINA RETAIL ALLOCATION OF THE REVENUE REQUIREMENT RELATED TO THE EXCESS DEFERRED TAX LIABILITY?

A. Duke Power's annual cost of service studies include an allocation factor for Accumulated Deferred Income Tax. Duke Power used this allocation factor from its cost of service

study prepared in 2004 to calculate the South Carolina retail allocation of the revenue requirement related to the excess deferred tax liability.

Q. WILL THE COMPANY APPLY THE DEFERRED TAX DECREMENT RIDER AS A REDUCTION IN THE FUEL FACTOR WHEN COMPUTING ITS UNDER- OR OVER-RECOVERY FOR THE NEXT TEST PERIOD?

A. No. As reflected in Ms. Hager's testimony, Duke Power is requesting approval of a fuel factor and a deferred tax decrement resulting in a net billing factor. Duke Power will exclude the deferred tax decrement in calculating its under- or over-recovery for the next test period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

JACOBS EXHIBIT 1

Calculation of S.C. Retail Allocation of Revenue Requirement on True-up of Deferred Taxes on Property, Plant & Equipment:

	As of 12/31/04
Revenue Requirement on True-up of Deferred Taxes on Property, Plant & Equipment	$152,925,164
S.C. Retail Allocation % from 2003 Cost of Service Study	25.3315%
S.C. Retail Allocation of Revenue Requirement on True-up of Deferred Taxes on Property, Plant & Equipment	$38,738,238
Projected S.C. Retail MWH Sales October 2005 - September 2006	22,363,176
Deferred Tax Decrement Rider in cents/kwh	(0.1732)